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May 16, 2006

HAND DELIVERED

Legal Document Examiner
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: R 06-03-004

Legal Document Examiner:

Enclosed for filing in the above-referenced proceeding are the original and five (5) copies of the **Comments of R. Thomas Beach on the Staff's Proposed Program for the California Solar Initiative.** Copies have been served on all parties of record in this proceeding.

Please return a filed-stamped copy to us using the enclosed self-addressed and stamped envelope. Thank you for your attention to this matter.

Sincerely,

R. Thomas Beach

Enclosures

cc: The Honorable Michael R. Peevey, President
The Honorable Dian Grueneich, Commissioner
The Honorable Rachelle Chong, Commissioner
The Honorable John Bohn, Commissioner
The Honorable Geoffrey F. Brown, Commissioner
Presiding Administrative Law Judge Dorothy Duda
All parties on Service List in R 06-03-004

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BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues	)))))	Rulemaking 06-03-004 (Filed March 2, 2006)

Comments of R. Thomas Beach on the Staff's Proposed Program for the California Solar Initiative

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May 16, 2006

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues	)))))	Rulemaking 06-03-004 (Filed March 2, 2006)

Comments of R. Thomas Beach on the Staff's Proposed Program for the California Solar Initiative

Pursuant to the Rulings of Administrative Law Judge Dorothy Duda dated April 25 and May 9, 2006, R. Thomas Beach respectfully files these opening comments on the proposal by the Commission's Energy Division on performance-based incentives and other program elements for the California Solar Initiative (CSI).[1]

I file these comments as the owner and operator of a 2.4 kW photovoltaic (PV) system that has been installed on my family's home in Kensington, California since January 2003. We are interconnected to the Pacific Gas & Electric (PG&E) system as a net metering customer under PG&E's E-NET tariff. Our PV system provides most of my family's electrical requirements, and has resulted in a zero net energy bill from PG&E for the past two years. In addition, through my consulting firm, Crossborder Energy, I have participated actively for many years in the Commission's proceedings on avoided costs and rate design for the electric utilities in California, including the ongoing rulemaking on the Commission's avoided cost methodology, R. 04-04-025. I am filing these comments because I believe that the design of the CSI program should be informed by the best available information from R. 04-04-025 and recent academic research on the temporal value of power produced by the PV systems whose installation the CSI seeks to encourage. In particular, I will focus my comments on Section 2.4 of the Staff Proposal, the proposed Expected Performance Based Buydown (EPBB) for small PV systems (less than

[1] Hereafter, the "Staff Proposal."

100 kW). However, my comments also are relevant to the design of a Performance Based Incentive (PBI) structure for large commercial installations (greater than 100 kW), as presented in Section 2.3 of the Staff Proposal. Accordingly, I will conclude these comments with observations on the design of a PBI program for large PV installations.

1. The Design Factor in the EPBB Incentive (Section 2.4)

The Staff Proposal would continue to pay the owners of small PV systems an upfront incentive that "buys down" the initial capital expense of the system; the staff proposes that this incentive would reflect the expected performance of the system. Staff proposes that the EPBB incentive should be based on the formula

CSI EPBB Incentive Paid = Incentive Rate x System Rating x Design Factor

This formula is the same as the incentive formula under the current CEC-administered Emerging Renewables Program (ERP), with the significant addition of the "Design Factor." The Design Factor would be "the ratio of simulated output for the system that is specified divided by the simulated output for a system with an identical rating that is oriented south and tilted 30 degrees with no shading," that is:

Design Factor = Minimum Simulated Output for Designed System /
Simulated Output for Fixed 30° South-Facing System Without Shading

The Staff Proposal is not clear on what constitutes the "output" of a PV system; I assume that the staff refers to annual expected kWh production. Staff believes that the Design Factor should not consider geographical location, in order not to discriminate against customers in areas with less solar insolation. The Staff Proposal suggests the use of existing, publicly-available calculation tools to determine the simulated outputs for both the design and reference system outputs, such as the PVWATTS program developed by the National Renewable Energy Laboratory (NREL). Given the staff's desire not to consider geography, I presume that the staff's Design Factor calculations would choose a "representative" location in the state at which to make all calculations, although the Staff Proposal is silent on this point. I note that the impact of geography on the Design Factor will be minimal so long as solar data for the same location are used in the calculation of both the numerator and the denominator of the Design Factor.

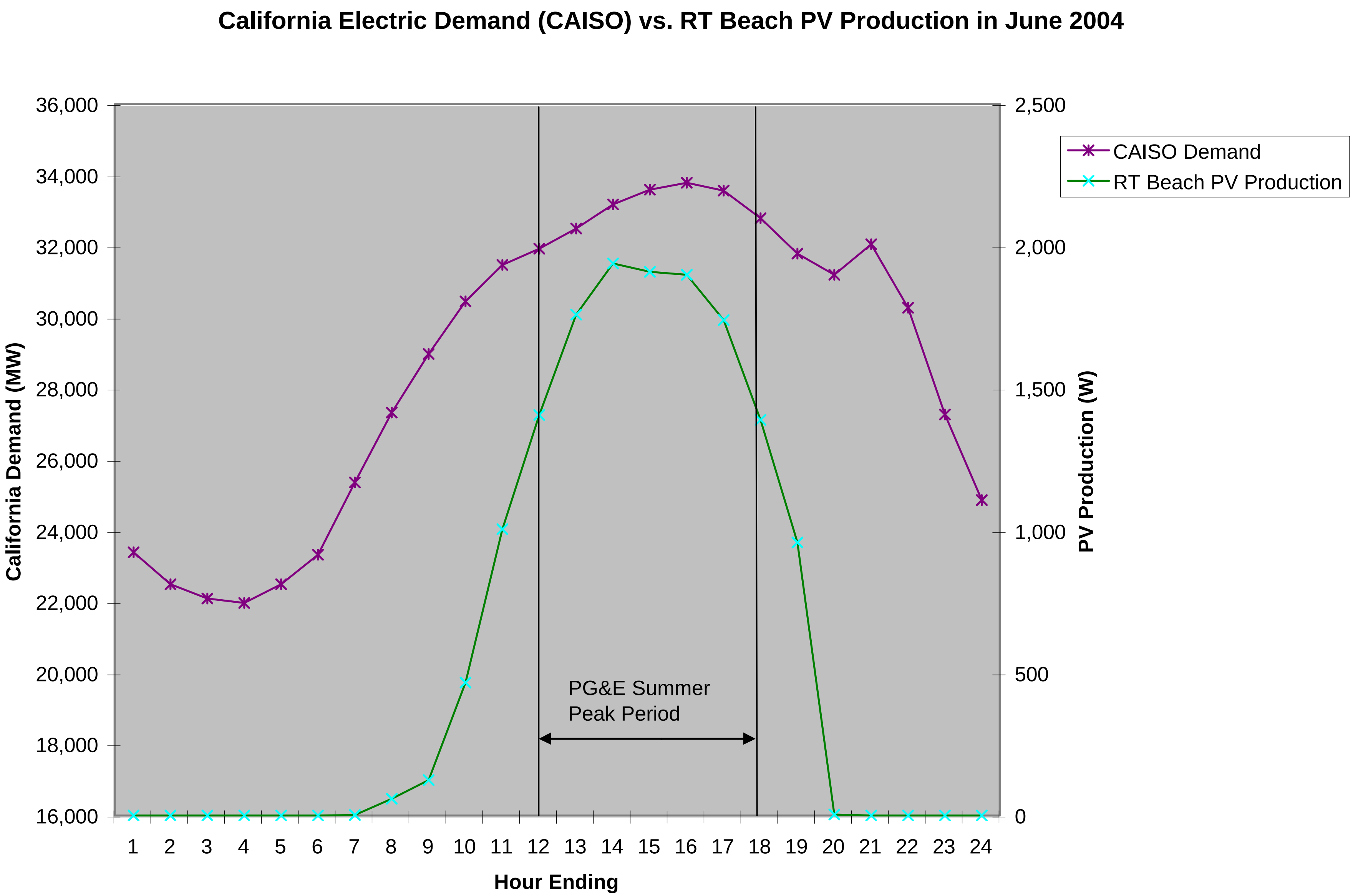
The Staff Proposal's Design Factor thus uses a south-facing system at a 30° tilt as the reference system. The annual kWh output of such a system will be close to the maximum for a system with a fixed tilt. In contrast, the staff's Design Factor for west-facing systems will be substantially less than 1.0. Using the PVWATTS calculator at a representative sample of locations in California,[2] I calculate that the Design Factor for a west-facing system at a 30° tilt will be in the range of 0.80 to 0.84, reflecting the 16% to 20% lower annual output of such a system compared to the reference south-facing system. The Staff Proposal thus would provide a significantly lower EPBB incentive for west-facing systems.

2. The Time-Varying Value of PV Production (Sections 2.3 and 2.4)

My principal concern with the staff's Design Factor is that it fails to consider the fact that, as you change the orientation of a PV system from south-facing to west-facing, you will increase the value of the power that the system produces. The production of a south-facing system will peak at noon, and, assuming that the local utility has a summer on-peak period of noon to 6 p.m., no more than 50% of weekday production will fall into the on-peak period. In contrast, the output of a west-facing system will peak between 2 and 4 p.m., and a much greater percentage of its output will fall into the valuable on-peak period. For example, my system is oriented at an azimuth angle of 250° (i.e. it faces 20° south of west). **Figure 1** shows the recorded hourly average production from my PV system over the month of June 2004. In this month, 74% of my production fell into PG&E's noon to 6 p.m. on-peak period. Figure 1 also plots the hourly average demand for electricity on the California ISO grid in June 2004, showing that the output

[2] The locations I sampled are San Francisco, Fresno, Daggett, and Los Angeles. The PVWATTS calculator is available at http://rredc.nrel.gov/solar/codes_algs/PVWATTS/.

Figure 1



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of my more westerly PV system peaks at a time that more closely coincides with the CAISO's system peak, compared to a south-facing system that peaks at noon. This suggests that the increased value of power production from west-facing PV systems may offset the lower annual average output from such systems, compared to the reference south-facing system.

Indeed, recent academic work on the time-varying value of PV production in California supports this conclusion. **Attachment A** is a March 2005 study, "Valuing the Time-Varying Electricity Production of Solar Photovoltaic Cells," authored by Severin Borenstein, the Director of the U.C. Berkeley Energy Institute. Dr. Borenstein uses several hourly wholesale price series (both actual CAISO data and simulated prices) to value the PV production of systems facing south, southwest, and west at three locations in California. Tables 2 and 3 of his study show that the difference in the total value of PV production between south- and west-facing systems is much less than the 14% to 16% difference in annual production. For several of the wholesale price series that Dr. Borenstein examined, the west-facing system out-performed the reference south-facing array; generally, the southwest-facing system produced power with the greatest total value. Dr. Borenstein also examined whether a standard time-of-use retail rate tariff (instead of hourly pricing) would produce a correct valuation of PV production. He concludes that a TOU rate structure produces results similar to hourly pricing, and corrects most of the distortions of a single flat rate that does not vary with time.

My colleague Patrick McGuire and I have performed an analysis similar to Dr. Borenstein's work, using the Commission's adopted avoided cost model, developed by Energy & Environmental Economics (E3).[3] We used PVWATTS to project the hourly production of a 4.0 kW (DC) PV system in San Francisco, Fresno, Daggett, and Los Angeles, for both south- and west-facing orientations at a 30° tilt. We then used the E3 model to project hourly avoided costs in each of these locations, and weighted the hourly profile of avoided costs by the hourly

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[3] In D. 05-04-024, the Commission approved the use of the E3 model for cost-effectiveness evaluations of energy efficiency programs. The current version of the E3 model (version "cpucAvoided26.xls") is available at www.ethree.com/cpuc_avoidedcosts.html.

production from each PV system.[4] The result is a "PV-weighted" avoided cost for each location and array orientation. **Table 1** presents our results. The top section of the table shows the average annual production, in kWh, for each location and orientation, and demonstrates that the west-facing arrays produce 16% to 20% fewer kWh on an annual basis. The bottom section presents the "PV-weighted" E3 avoided cost for each location and array orientation. Finally, at the bottom of the table we compare the value of the power produced by south- and west-facing systems, valued at the time-of-use rates in PG&E's E-6 and E-7 residential time-of-use schedules. Clearly, the value of PV production, per kWh produced, is significantly higher for the west-facing arrays than for the south-facing arrays. Indeed, the higher value of the production from the west-facing systems offsets much of the reduction in annual kWh output.

3. Revising the Design Factor to Reflect the Time-Varying Value of PV (Section 2.4)

We agree with staff that the Design Factor should be relatively easy to calculate, using existing public-domain tools such as PVWATTS. We do not believe that it is necessary to calculate the exact value of the power produced from each new PV system, as models such as E3's avoided cost model require significant expertise to use and substantial effort to update. The results we have presented above suggest to us that, as the azimuth angle of a PV system moves from south to west, the reduction in annual output is substantially offset by the higher value of the power produced. This suggests to us two relatively simple revisions to the staff's Design Factor:

1. The Design Factor should not penalize PV systems that are oriented at any azimuth between south and west; within this range of azimuths, the Design Factor should consider only the tilt angle.

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[4] Our results for the PV-weighted avoided costs are conservative in that we did not assume any correlation between the days with the highest PV output and the days with the highest avoided costs, even though one would expect high PV output on clear, sunny, hot days when electric demand is high. Dr. Borenstein did attempt to make such a correlation in his work, however.

Table 1

Increased Value of West-Facing PV Output

1. AC Power Output (annual kWh)

	Array Orientation			South to West
	South	West	Difference	Percent Change
San Francisco	5,803	4,843	(961)	-17%
Fresno	5,850	4,840	(1,010)	-17%
Daggett	6,819	5,427	(1,393)	-20%
Los Angeles	5,885	4,964	(921)	-16%
Average	6,089	5,018	(1,071)	-18%

Source: NREL PVWATTS calculator.

2. PV Weighted E3 Avoided Costs ($/MWh)

	Array Orientation			South to West
	South	West	Difference	Percent Change
San Francisco	95.0	100.6	5.6	6%
Fresno	102.8	115.1	12.3	12%
Daggett	103.7	120.2	16.5	16%
Los Angeles	108.6	118.4	9.8	9%
Average	102.5	113.6	11.0	11%

Source: E3 version cpucAvoided26 hourly avoided costs weighted by NREL PVWATTS hourly PV production.

3. PV Weighted PG&E TOU Rate ($/MWh)

	Array Orientation			South to West
	South	West	Difference	Percent Change
PG&E E-6	132.2	144.2	11.9	9%
PG&E E-7	136.2	159.1	22.8	17%

Source: PG&E E-6 and E-7 TOU rates weighted by NREL PVWATTS PV production by TOU period, for Fresno.

2. With respect to the tilt angle, the Design Factor should be based on summer[5] production, not annual production. This will encourage installations that maximize summer output.

Thus, for systems that face any direction from south to west, the Design Factor should be:

Design Factor = Minimum Simulated <u>Summer</u> Output for Designed System / Simulated <u>Summer</u> Output for Fixed 30° Tilt <u>At Same Azimuth Angle</u> Without Shading

This Design Factor should apply to virtually all systems, as most PV systems are oriented at an azimuth angle from 180° to 270° (i.e. face a direction from south to west). For the rare systems with azimuths less that 180° (i.e. east of south), the reference system in the denominator of the Design Factor should be a fixed 30° tilt facing south without shading; for azimuths greater than 270° (i.e. north of west), the reference should be a fixed 30° tilt facing west without shading.

In my opinion, this revision to the Design Factor will encourage PV systems to be installed on a broader range of existing buildings and will allow greater flexibility in the siting, design, and construction of new buildings with integrated PV systems. Such flexibility will be important if a million solar systems are to be installed in the state.

Furthermore, the Commission should consider now the potential impacts of integrating 3,000 MWs of solar PV into the electric grid, an amount that could represent as much as 5% of the CAISO's installed generating capacity. If all of these systems face south, their output will rise, peak, and decline at the same time, producing greater challenges / headaches for system operators than if the systems have azimuth angles that are distributed over the range from south to west. In other words, a diversity of orientations from south to west will moderate the rate at which total PV output changes over the course of a day.

[5] The summer season should be assumed to be May through October. This is the tariffed "summer" for PG&E and SDG&E; Edison's summer (June - September) falls within this period, as well.

4. Implications for the Design of a Performance-Based Incentive (Section 2.3)

The time-varying value of PV production also has implications for the design of a performance-based incentive (PBI) for large commercial solar installations. The Staff Proposal, as well as the pre-workshop comments of many parties, favor the use of a simple PBI mechanism that pays a flat per kWh incentive rate for PV production over a defined period of years. This rate would not be adjusted based on the orientation of the PV system. As a result, such a structure favors south-facing systems that maximize annual kWh output. Because the power from west-facing systems has demonstrably higher value to the electric system, I suggest the use of an adjustment to the PBI rate for systems that are oriented between south (180°) and west (270°). This adjustment, which I call the Orientation Factor, would be a multiplier greater than 1.0 that would be applied to the base PBI rate:

Adjusted PBI Rate = Base PBI Rate x Orientation Factor, where

Orientation Factor = Simulated Summer[6] Output for Fixed 30° Tilt South-Facing Without Shading / Simulated Summer Output for Fixed 30° Tilt at the Azimuth of the Designed System

The Orientation Factor uses a constant 30° tilt in order not to encourage unduly steeply-inclined west-facing systems that produce little power. Based on PVWATTS output for Fresno, the maximum Orientation Factor would be 1.125 (112.5%), for systems that face due west. The Orientation Factor would only be used for systems that are oriented between south (180°) and west (270°).

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[6] Again, as with the Design Factor, the summer season should be assumed to be May through October.

I have appreciated the opportunity to present these comments to the Commission on the design of the CSI program.

Respectfully submitted,

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May 16, 2006

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served a copy of the foregoing document, **Comments of R. Thomas Beach on the Staff's Proposed Program for the California Solar Initiative,** by Electronic Mail where possible and First-Class Mail where not, on all known parties to R 06-03-004, named on the service list attached to the original certificate of this document pursuant to the Commission's Rules of Practice and Procedure.

I declare under penalty of perjury that the foregoing is true and correct.

Executed at Berkeley, California, Tuesday, May 16, 2006.

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Christa Goldblatt

Attachment A

Center for the Study of Energy Markets,
Working Paper No. 142

"Valuing the Time-Varying Electricity Production
of Solar Photovoltaic Cells"

prepared by Severin Borenstein,
Director, U.C. Berkeley Energy Institute

March 2005

http://www.ucei.berkeley.edu/PDF/csemwp142.pdf

CSEM WP 142

Valuing the Time-Varying Electricity Production of Solar Photovoltaic Cells

Severin Borenstein

March 2005

This paper is part of the Center for the Study of Energy Markets (CSEM) Working Paper Series. CSEM is a program of the University of California Energy Institute, a multi-campus research unit of the University of California located on the Berkeley campus.

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Valuing the Time-Varying Electricity Production of Solar Photovoltaic Cells

Severin Borenstein[1]

March 2005

Abstract: Solar PV panels generate electricity only during daylight hours and generate more electricity when the sun is shining more intensely. As a result, in summer-peaking electricity systems, such as California and most of the U.S., power from PVs is produced disproportionately at times when the value of electricity is high. Thus, a valuation of solar PV electricity production that uses only the *average* wholesale cost of electricity will tend to undervalue the power. Yet, that is what happens by default in many installations because solar PVs are generally located at the end-user's premises and those end-users are often billed on a flat per kilowatt-hour rate that does not reflect time-varying valuation. As a result, the benefits to many owners of solar PV in reduced electricity bills do not reflect the true time-varying valuation of the power the panels produce. I use solar PV production information in conjunction with wholesale price data and simulations to estimate the actual wholesale value of power from solar PVs and the degree of bias that occurs from using a constant price to value electricity generated by solar PVs. I find that in the California locations I analyze, the most credible long-run valuation of solar PV power is 29%-48% greater than results from valuation at a flat-rate tariff, depending on the location of the PV panels. If the end user is billed on a time-of-use tariff (a simple peak/off-peak price system), however, I find that the misvaluation of wholesale power from solar PVs is approximately zero.

[1] Director, University of California Energy Institute (www.ucei.org), E.T. Grether Professor of Business Administration and Public Policy at the Haas School of Business, University of California, Berkeley (faculty.haas.berkeley.edu/borenste) and National Bureau of Economic Research (www.nber.org). Email: borenste@haas.berkeley.edu. I'm grateful to Meredith Fowlie for helpful comments and excellent research assistance. I thank Duncan Callaway for providing generation data for solar PV installations and explaining their real-world constraints.

As fossil fuel prices have risen and concerns over greenhouse gases and global climate change have increased, alternative technologies for producing electricity have received greater attention. Among the technologies that may help to address these concerns is solar photovoltaic cells (PVs), which capture solar radiation and convert it into electrical energy. Such cells are generally located at the site of the end user and thus are a form of distributed generation.

While there are many important questions in the analysis of the economics of solar PV, in this paper, I attempt to address just one of them: accounting properly for the time-varying electricity production of solar PVs. Solar PVs generate electricity only during daylight hours and generate more electricity when the sun is shining more intensely. As a result, in summer-peaking electricity systems, such as California and most of the U.S., power from PVs is produced disproportionately at times when the value of electricity is high. Thus, a valuation of solar PV electricity production that uses only the *average* wholesale cost of electricity will tend to undervalue the power.

Yet, that is what happens by default with many solar PV installations, because they are generally located at the end-user's premises and those end-users are often billed at a flat per kilowatt-hour rate that does not reflect time-varying valuation. Thus, the benefits to many owners of solar PV in reduced electricity payments do not reflect the true time-varying valuation of the power they produce.

In this paper, I use solar PV production information in conjunction with wholesale price data to estimate the actual wholesale value of power from solar PVs and the degree of bias that occurs from using a constant price to value electricity generated by solar PVs. In section II, I discuss briefly the many issues raised by solar PV power in order to clarify where this research fits in the debate. In section III, I present the basic approach to valuing solar PV power using real-time electricity prices and comparing that valuation to one based on a flat-rate retail pricing plan. In section IV, I discuss the data I use to represent solar PV power production and in section V I discuss the data I use to value that power. In section VI, I present results from a number of different approaches to valuing PV power. I find that the wholesale value of solar PV power is substantially greater than would result from simply valuing solar PV power at the average wholesale cost – a flat-rate energy tariff – regardless of when it is produced. Using what I believe to be the best representation of the time-varying value of power from solar panels in California, I find that accounting for the time of production increases the value of solar PV power by 29%-48% across three different locations in the state.

This significant gap in the valuation of power from solar panels could substantially reduce the end user's incentive to install solar panels, but in section VII I point out that the problem is less widespread than one might think. I show that a customer on simple time-of-use (TOU) rates – a peak/off-peak tariff in the winter and a peak/shoulder/off-peak tariff in the summer – receives valuation for the power produced from solar panels that is on average very close to the actual wholesale value of the power. The majority of commercial and industrial customers with solar panels are on such TOU rates as are a significant number of household customers with solar panels. For such customers, retail rates appear to effectively approximate the time-varying value of solar PV power.

II. (Mis)valuing Solar Photovoltaic Power

The problem raised here is part of a larger issue in valuing distributed generation and energy efficiency. These energy sources are on the customer side of the meter. Thus, customers reduce their retail demand from the grid by utilizing these technologies. The private savings from such retail demand reduction – the reduction in the customer's retail bill – differs from the social savings for a number of reasons.

To see the difference, it is useful to decompose the retail bill into three components: (i) wholesale energy, (ii) transmission and distribution (T&D) costs, and (iii) adjustments to account for capital gains or losses from past financial and other commitments. Most of the costs from all three components are collected through a per-kilowatt-hour retail price.

By definition, the third component – adjustments to reflect past sunk gains or losses – does not reflect an incremental social cost from consumption. So, to the extent that this is a positive per-kWh charge to recoup past losses, this increases the retail price compared to the true social incremental cost.[2] Similarly, some of the cost of transmission and distribution is a fixed cost that does not vary, even in the long run, with the amount that an individual customer consumes. So, again, the retail price tends to overstate the social incremental cost of consumption and causes the customer to overvalue activities that reduce consumption from the grid, including distributed generation and energy efficiency.

Some of the transmission and distribution cost, however, may reflect capacity investments that are necessary on the margin to meet peak demand. Depending on the level of investment that actually occurs to meet peak loads compared to the level that would be necessary if retail power prices changed over time to reflect scarcity in T&D, retail prices that include a flat rate charge for T&D may lead to valuation of on-site generation, such as solar PV, that is too high or too low.[3]

Distributed generation is also often supported for its security value. The argument is that small on-site generation makes the electricity system less vulnerable to terrorist attack, because (a) it reduces the number and degree of "high-value" targets where a single strike could cut power to many users, (b) it reduces the grid instability that could result from loss of a large power generator or transmission line, and (c) in the case of solar PV, it reduces the use of dangerous fuels that create additional potential hazards from attack.[4]

Environmental externalities are, of course, often cited as a reason to place greater social value on some alternative forms of electricity generation, including solar PVs.[5] With growing evidence of global climate change linked to greenhouse gas emissions from burning of fossil fuels, these arguments take on increased weight. Electricity from PVs reduces both

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[2] To the extent that a utility reduces the retail price below social incremental cost to distribute sunk gains, this decreases the retail price relative to the true social incremental cost.

[3] Spratley (1998) discusses the value of solar PV panels in reducing T&D expense and references a number of studies of the effect.

[4] See Asmus (2001).

[5] This is obviously a vast literature. Sundqvist (2004) provides an overview and tries to reconcile disparate estimates of the environmental externalities.

greenhouse gases and regional pollutants such as NO_x and SO_2.[6]

On the other hand, there are concerns about the intermittency of supply from some generation sources. Power generation that is (exogenously) intermittent, such as solar PV or wind, requires that the market adjust either on the demand or supply side as the power from these sources fluctuates. Some argue that this makes the grid more difficult to stabilize, but others dispute this, point out that wind power is used in much larger quantities on some grids in Europe. Intermittency surely imposes some cost, but the magnitude of cost is open to a great deal of dispute.

The final way in which power from solar PV may be misvalued, and the issue that I address in this paper, stems from the fact that the retail price of energy for most residential and small commercial customers does not vary according to the time at which the power is consumed. Assuming that the retail price of electricity is set to cover the wholesale cost overall (after subtracting the components for T&D and sunk losses/gains, as discussed above), this means that each kilowatt-hour produced by a solar PV installation will save the customer the system weighted average price of energy regardless of when the solar power is actually produced.[7] If the PVs produced electricity at all times in proportion to system load, this would be an accurate valuation, but that is not the case. In reality, PV power production at most locations is disproportionately higher during periods when system demand is high and disproportionately lower during system off-peak periods, *e.g.,* zero at night.

III. Analytic Approach to Valuing Time-Varying Solar PV Power

The premise of this analysis is that power from solar PVs is misvalued because it is recorded as a reduction in the end-use customer's demand. If the end-use customer faces a

[6] For pollutants regulated under a cap-and-trade permit system, the variable cost of generation would include the cost of permits. Whether the price of permits raises the marginal cost of electricity production by the socially efficient amount, however, depends entirely on getting the capped number of permits "right."

[7] If different load profiles are used for different classes of customers, the customer's savings will be the weighted average price of energy for the class in which the customer is placed. The basic point, however, is unchanged.

flat retail rate, the savings to the customer from on-site solar PV production are the same regardless of whether the production occurs when demand and prices are low or high.

Abstracting from non-energy retail charges (T&D and sunk losses/gains), in the long run, flat retail rates must cover the system energy costs, just as time-varying prices must do. Thus, to avoid biasing the analysis, one would want to calculate a flat rate that is revenue-neutral compared to real-time pricing. In practice, this means setting a flat rate that is the system-quantity-weighted average wholesale price.[8]

Assume that we have a time series of system wholesale prices, P_t, and system demand quantities, Q_t, and that those system demand quantities were generated by a flat retail price that covered wholesale costs. That flat retail rate would be

$$\bar{P} = \frac{\sum_{t=1}^{T} Q_t \cdot P_t}{\sum_{t=1}^{T} Q_t}.$$

Now assume that a retail customer on a flat-rate retail tariff has a solar panel installation that generates q_t of power in each hour. The customer's meter does not record time of use, so credit for generating occurs at the flat retail rate whether the customer is a net buyer or seller.[9]

On a flat-rate tariff, the customer's value of the power generated by the solar PV installation will be $V_{flat} = \bar{P} \sum_{t=1}^{T} q_t$, but the wholesale value of the power the PV installation generates is $V_w = \sum_{t=1}^{T} P_t q_t$. So, the customer will undervalue the PVs by $V_{diff} = \sum_{t=1}^{T} (P_t - \bar{P}) q_t$. My goal in this paper is simply to calculate V_{diff} for plausible time series of P_t, Q_t and q_t. In the next section, I discuss data for the solar PV installation, q_t. In the following section, I discuss data for system prices and quantities, P_t and Q_t.

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[8] A flat rate based on the shapes of the customer's net demand before versus after the customer installs solar PV panels would more accurately value the solar PV power, but such "load profile" changing has not occurred with solar power. Studies such as the present analysis could give guidance on creation of such a load profile for a customer with solar PV panels.

[9] I'm assuming that the customer's meter can actually "run backwards" if the customer at any point in time is generating more power than is being used onsite, so the customer can sell power back to the grid.

IV. The Time-Varying Production of Solar Photovoltaic Cells

Solar PV cells produce power when the panels in which they are embedded are hit by solar radiation. This occurs only during the daytime and, within a day, varies according to the angle of the sun. For the same reason, PV production varies with the seasons, the latitude of the location in which the building is located, and the direction and angle at which the panels are mounted. Production is also affected by the weather, both because cloud cover can reduce the energy received by the panel and because the PV cell production declines if the cells get too hot.

There are two conceptual approaches to establishing the time-varying production of PVs. The first would be to obtain actual "metered" data from solar PV panels that are currently in use. The second is to use simulation models that control for most of the factors that affect production. Each approach is imperfect.

I have not located metered data. Such data would have the advantage of representing an actual installation of PV panels and would automatically take into account variation in solar radiation. These data, however, would also be idiosyncratic, affected by the particular installation, orientation, upkeep, obstructions, and other factors that affect the productivity of solar PVs. Without a sample from multiple installations, it would be difficult to know how idiosyncratic the data are.

I have found simulation data from three sources. The most sophisticated seems to be TRNSYS (A Transient System Simulation Program) based at University of Wisconsin. I obtained TRNSYS simulated production for a 10kW (DC) installed solar PV system in San Francisco, Sacramento, and Los Angeles.[10] For each location, the runs were done assuming the panels were mounted at a 30 degree angle facing, in different runs, South, Southwest, and West.

Weather data for TRNSYS come from the U.S. National Renewable Energy Laboratory (NREL). The weather data set is TMY2, which is described by NREL as, "[t]he TMY2s are data sets of hourly values of solar radiation and meteorological elements for a

[10] I'm grateful to Duncan Callaway of Davis Energy Group for doing the TRNSYS runs that produced the simulated PV production.

1-year period. Their intended use is for computer simulations of solar energy conversion systems and building systems to facilitate performance comparisons of different system types, configurations, and locations in the United States and its territories. Because they represent typical rather than extreme conditions, they are not suited for designing systems to meet the worst-case conditions occurring at a location."

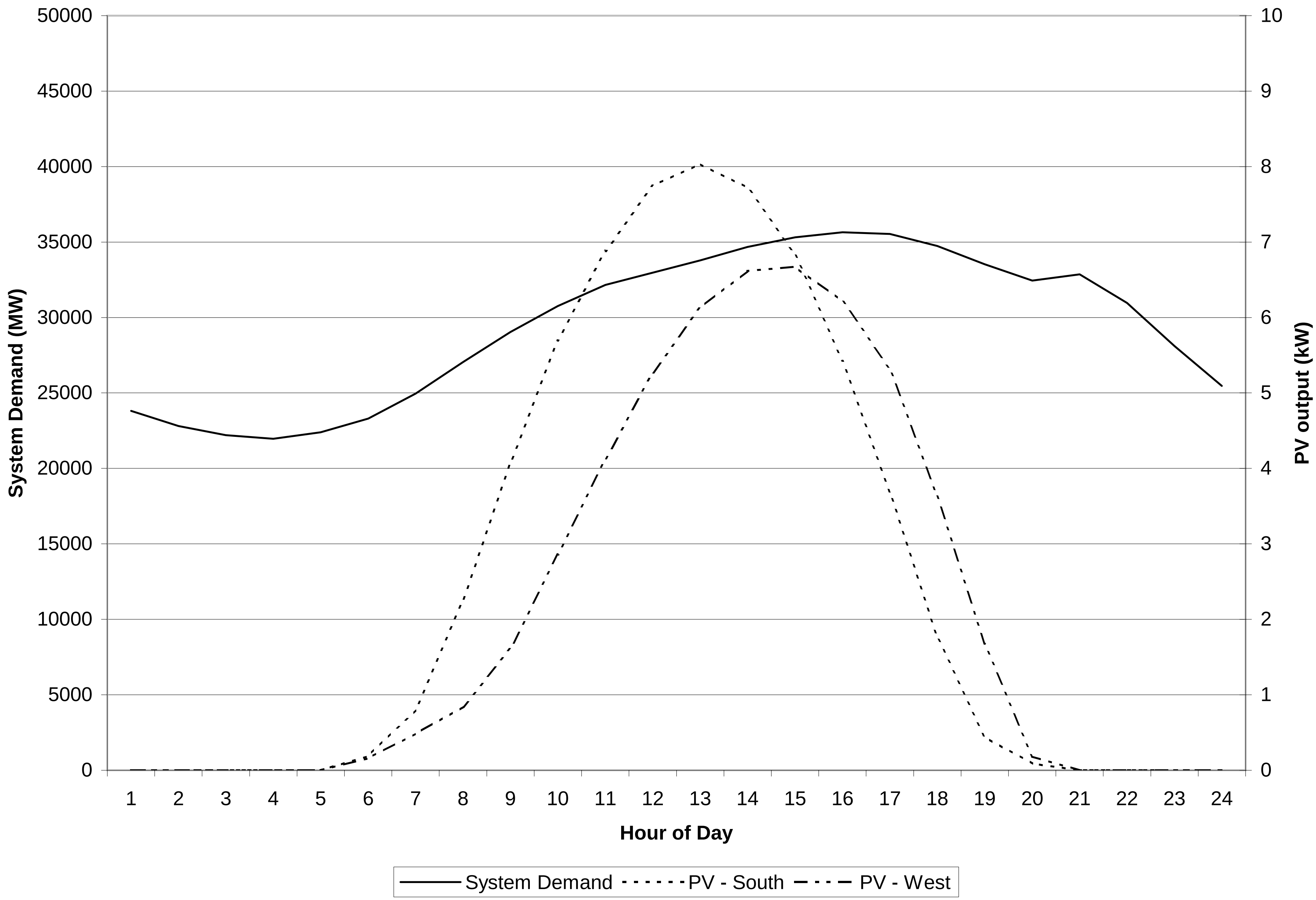
The TRNSYS model produces hourly simulated production data for one year. As I explain in the next section, I match these data to five years of electricity system data and prices. To do this, I start by simply repeating the simulated production data five times.

The TRNSYS solar PV production data have substantial day-to-day variation, reflecting weather variation. If these were actual metered data, the high-production days for the PVs would also be, on average, the high system demand days in a summer-peaking electricity system such as California. Because these data are derived separately from the system quantity and price data, however, this relationship will be less strong than it would be in actual use. For instance, the simulated July weekday afternoon solar PV production is on average higher than the simulated February weekday afternoon solar production and the July weekday afternoon system demands are on average higher than the February weekday afternoon system demands. Within July weekday afternoons, however, the idiosyncratically higher PV production days from the simulation would not necessarily correspond in the dataset to the idiosyncratically higher system demand days. I explain below how I address this issue.

Figure 1 demonstrates the basic fact that motivates this analysis. For a July weekday, Figure 1 illustrates the hourly average demand profile in the California Independent System Operator (ISO) system and the average solar PV production of a south-facing and a west-facing installation in San Francisco. Solar PV production not only peaks in the middle of the day, when demand peaks, it does so disproportionately to demand.[11] Figure 1 also demonstrates that by turning the solar panels more towards the west, peak production from the solar panels can be more closely synchronized with system demand, but at a cost of lower overall production levels.

[11] In part, of course, this is simply due to the fact that solar PV produces no power when it is dark.

FIGURE 1: Hourly Average System Demand and Solar PV Production for July Weekdays



V. Realtime Prices for Valuing the Power from Solar PVs

As with the solar PV production data, there are two conceptual approaches to valuing solar output at wholesale prices. The first is to use an actual price series from the market in which the PV installation is located. The second is to use simulated data from a model of pricing in a competitive wholesale electricity market. I use each of these approaches.

The analysis I do using actual market prices takes the relevant hourly zonal price from the California ISO's real-time market for the 5-year period, 1999-2003: the northern zone (NP15) price for analysis of Sacramento and San Francisco, the southern zone (SP15) price for analysis of Los Angeles. While a price series from actual market operation has the obvious advantage of credibility, it may also have a number of disadvantages compared to simulated prices. Most important is the fact that investment in generating capacity might not be in long-run equilibrium during the period in which the prices are observed. If there is excess capacity, then peak prices are likely to be damped relative to the long-run equilibrium price distribution, penalizing technologies that produce more at peak times, such as solar PV. Of course, if there is a capacity shortage during the observed time, the opposite could be true. In addition, wholesale prices may be restrained by regulation, such as a price cap. This was the case in California where a wholesale price cap was binding in many hours during the period I examine.

I see no useful way to correct the actual price data for under- or over-capacity, though the simulation approach does address that issue. The price cap constraint can be addressed in an *ad hoc* way by raising the price in hours when the cap was binding. I create such an augmented price in a rather simplistic way: during the periods in which the price cap was $250/MWh, I reset the price to $750/MWh in any hour in which the actual price was above $249 and during the periods in which the price cap was $500/MWh, I reset the price to $750/MWh in any hour in which the actual price was above $499. I do not reset the price in any hours in which the price cap was $750/MWh, the highest level it was ever set. I also do not reset the price for any hours after June 2001. The FERC imposed a low (and variable) price cap in June 2000, but by that time the market prices had crashed and the price cap was almost never binding. The reason that I do not raise any prices above $750 is that it is unlikely that the competitive market price was ever above that level during this time period. While solar PV capacity would have helped to undermine market power during the California electricity crisis, so would have any other capacity. More importantly, with long-term contracts now a significant feature of the market, and generally more understanding of the vulnerability of electricity to market power, it seems unlikely that we will see such inflated margins again as a result of seller market power.

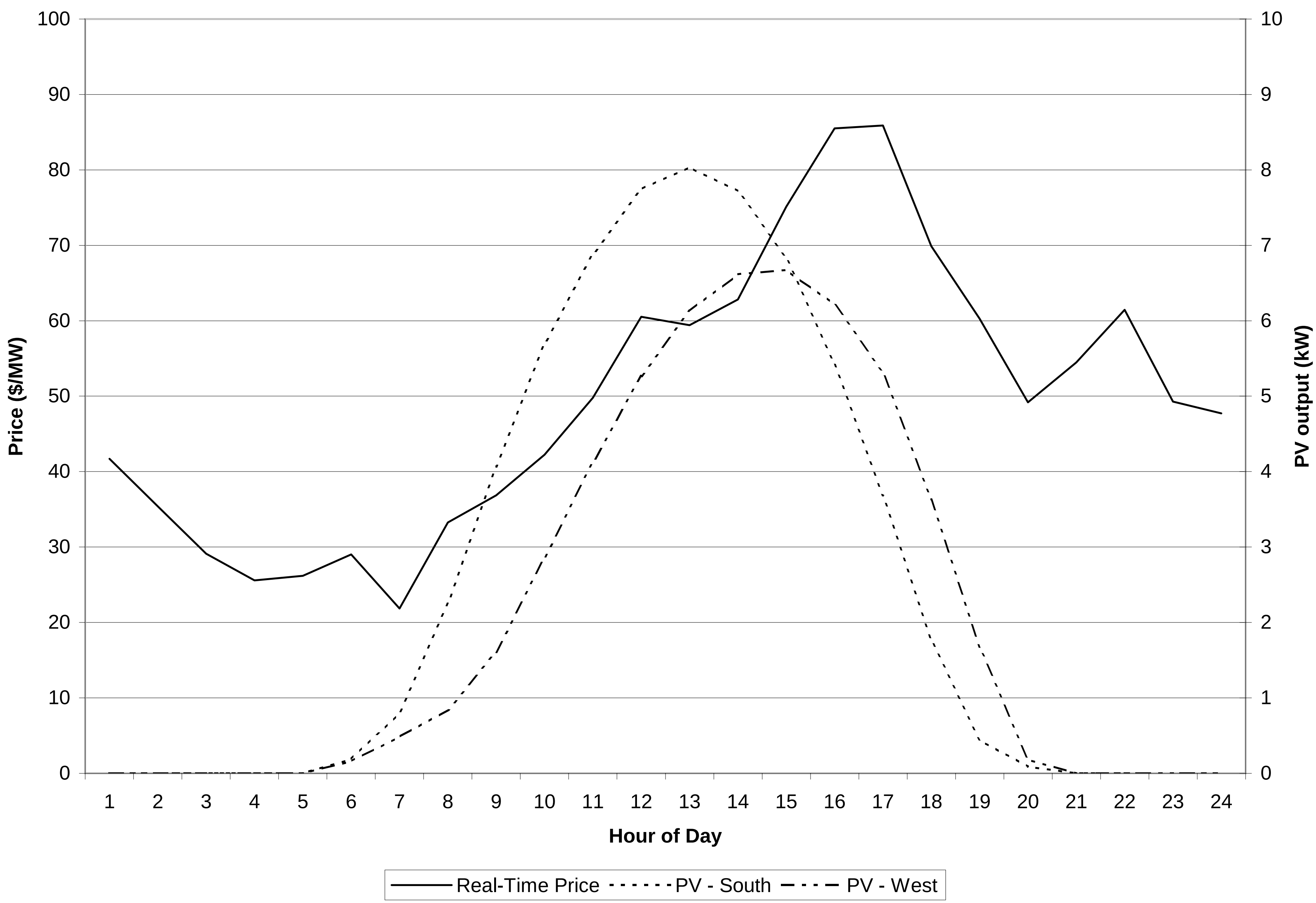
Figure 2 is the same as Figure 1, but replaces system demand with the real-time wholesale price for northern California. It demonstrates that PV production occurs disproportionately times of high wholesale prices.

An alternative to an actual wholesale price series is to use prices from a simulated long-run model of wholesale electricity markets. In separate work (Borenstein, 2005), I have constructed and simulated such a model under various demand assumptions for the same market and time period as is covered by the actual price data. The model takes the actual distribution of hourly demand and calculates the capacities of three kinds of generation technologies that would be installed in a long-run equilibrium in which firms are competitive in the short-run – all sellers are price-takers – and competitive in the long-run – sellers enter and exit to the point that all producers are just breaking even. The model includes a baseload technology with high fixed costs and low marginal costs, a peaker technology with low fixed costs and high marginal costs, and a mid-merit technology with moderate levels of both costs.

On the demand side, the model posits that some share of customers are on real-time pricing and the remainder are charged a flat rate. The effective wholesale demand elasticity is then determined by the share of customers on RTP and the amount of demand elasticity those customers display. For a range of very inelastic demands, however, the peaking capacity recovers all of its fixed costs in a small number of hours in which prices are very high, in some cases more than one hundred times greater than average prices. Thus, these simulated wholesale prices are much peakier than the actual prices that were observed. As I show below, the effect of revaluing solar PV power with these simulated realtime prices is greater than from using the actual market prices.

The simulated prices have the advantage that they are determined in a way that

Figure 2: Hourly Average Real-time Price and Solar PV Production for July Weekdays



assures that capacity recovers its capital costs. Importantly, however, in the simulation capacity cost recovery comes completely through energy prices. In a number of markets, capacity owners receive non-energy payments just for having capacity available. These payments tend to increase capacity and reduce energy price spikes. To the extent that capacity payments are made independent of the time at which the capacity produces energy, they will substitute for price spikes and will undermine the efficient long-run price signals sent by energy markets. By distorting efficient energy price signals in this way, they will reduce the economic appeal of technologies that produce disproportionately at peak times.

Unobserved Correlation Between Prices and Solar PV Production

The TRNSYS model produces typical solar PV production that includes random variation due to weather. But in actual markets that random weather variation is correlated with demand, and thus prices, in the system: clear, hot weather produces higher system demand and high prices. Up to a point, such weather also produces higher solar PV production. Thus, simply matching the simulated solar PV production with a price series will fail to account for the unobserved correlation between solar PV production and system prices. Omitting this effect will tend to undervalue the power from solar PV.

Without a series of actual solar PV production, it is not possible to overcome this problem directly. However, an adjustment to the data does permit a straightforward calculation of an upper bound on its effect. The adjustment is done by reordering the PV production data within certain time periods to match the highest PV production with the highest system demands.

For example, consider the 1-2pm weekday hours in July. With five years of data there are 106 such hours, during which system demands varied from 29923 MW to 45049 MW and prices varied from \$0.25/MWh to \$500.00/MWh. Simulated production from the assumed 10kW (DC) solar PV installation (in San Francisco with panels facing south) during these hours ranges from 5.88 MW to 8.24 MW (AC). One would expect, however, that an actual solar PV installation would produce more power in the hours that had higher system demand. To account for this, I reallocate the set of solar PV production data among these (1-2pm, July weekday) hours so that the highest hour of solar PV production corresponds to the highest system demand among these hours. I do this for every month/weekperiod/hour where "weekperiod" is either "weekday" – Monday through Friday, excluding holidays – or "weekend" – Saturday, Sunday and holidays. I do this adjustment separately for each of the nine PV production times series (panels in SF, LA, and Sacramento, each facing S, SW,and W).

This is a favorable assumption for valuing solar PV production. In reality, solar PV production in any of the locations I examine is positively correlated with system demand, but the rank-order correlation is far from perfect. The correlation is imperfect for at least two reasons. First, weather is imperfectly correlated across locations within the system, so high system demand may be due to sunny weather in other locations on the system while it is overcast at the location of the PV cells. Second, solar PV production increases with hotter, sunnier weather up to a point, but then declines beyond that point as further heating of the cell reduces its efficiency. Thus, while the unadjusted results understate the value of solar PV production, the results from this adjustment overstate the value.

VI. The Wholesale Value of Time-Varying Solar PV Power

The results of the calculations I've described are shown in Table 1. For each location, I calculated wholesale values using four different price series, which are the rows for each location. "Piso" north or south is the actual hourly spot price in the zone of the California ISO system in which the city is located, north for SF and Sacramento, south for LA. "PisoAugmented" is the hourly spot price with the adjustment for the low price caps that I described earlier.

The two Psim rows are price series from the simulations that I described earlier. The first number in the parentheses is the assumed elasticity of those customers that actually see the real-time price and therefore can respond to it. The second number is the share of total demand that is assumed to be charged real-time prices. I did the calculations with many simulated price series, but the results were quite similar for reasons I discuss below. In the table, I present two of the more extreme cases: Psim(-0.025,10%) creates an extremely inelastic demand curve with only 10% of customers facing real-time prices

TABLE 1: Change in Average Wholesale Value of Solar PV from Adjusting for Time-Varying Production

SACRAMENTO		South Facing PV				Southwest Facing PV				West Facing PV			
	flat-rate	RTP	pctg	RTP*	pctg	RTP	pctg	RTP*	pctg	RTP	pctg	RTP*	pctg
	tariff	value	diff	value	diff	value	diff	value	diff	value	diff	value	diff
Piso - North	$58.21	$60.30	4%	$63.38	9%	$62.13	7%	$65.37	12%	$62.90	8%	$66.10	14%
PisoAugmented	$74.37	$73.57	-1%	$80.38	8%	$76.05	2%	$82.77	11%	$76.68	3%	$82.71	11%
Psim(-0.025,10%)	$39.68	$51.12	29%	$52.39	32%	$58.25	47%	$59.72	50%	$63.89	61%	$65.31	65%
Psim(-0.100,99.9%)	$38.48	$50.13	30%	$51.97	35%	$55.10	43%	$57.59	50%	$58.84	53%	$61.76	60%
SAN FRANCISCO		South Facing PV				Southwest Facing PV				West Facing PV			
	flat-rate	RTP	pctg	RTP*	pctg	RTP	pctg	RTP*	pctg	RTP	pctg	RTP*	pctg
	tariff	value	diff	value	diff	value	diff	value	diff	value	diff	value	diff
Piso - North	$58.21	$61.12	5%	$64.62	11%	$62.49	7%	$66.16	14%	$63.09	8%	$66.83	15%
PisoAugmented	$74.37	$76.17	2%	$82.65	11%	$77.89	5%	$84.37	13%	$77.86	5%	$84.14	13%
Psim(-0.025,10%)	$39.68	$51.16	29%	$53.51	35%	$57.59	45%	$60.62	53%	$63.20	59%	$66.42	67%
Psim(-0.100,99.9%)	$38.48	$50.80	32%	$53.12	38%	$55.44	44%	$58.52	52%	$59.31	54%	$62.89	63%
LOS ANGELES		South Facing PV				Southwest Facing PV				West Facing PV			
	flat-rate	RTP	pctg	RTP*	pctg	RTP	pctg	RTP*	pctg	RTP	pctg	RTP*	pctg
	tariff	value	diff	value	diff	value	diff	value	diff	value	diff	value	diff
Piso - South	$53.10	$57.15	8%	$60.05	13%	$58.82	11%	$62.46	18%	$59.83	13%	$63.97	20%
PisoAugmented	$63.56	$67.03	5%	$71.48	12%	$69.05	9%	$74.64	17%	$69.77	10%	$76.06	20%
Psim(-0.025,10%)	$39.68	$48.12	21%	$49.62	25%	$54.34	37%	$56.39	42%	$59.91	51%	$62.23	57%
Psim(-0.100,99.9%)	$38.48	$47.30	23%	$49.77	29%	$51.15	33%	$54.67	42%	$54.66	42%	$58.83	53%

and even that group showing an elasticity of only -0.025; Psim(-0.100,99.9%) has nearly all demand on RTP and all exhibiting a less-inelastic demand of -0.1 elasticity.[12]

The "flat rate tariff" column shows the per megawatt-hour rate that is the system-quantity weighted average wholesale price over the sample period and therefore the break-even rate that would be charged for all energy if there were no time-varying pricing. The next column "RTP tariff" shows, for a PV installation facing South, the average valuation of the solar power if the value is the actual wholesale real-time price at the time at which the power was produced by the solar PV, using the TRNSYS production data. The following column shows the percentage difference from the valuation under the flat rate tariff. The "RTP* value" column shows the results after the adjustment for the unobserved correlation between prices and solar PV production discussed in the previous section, and again the percentage difference from the valuation under the flat rate tariff. The following columns do the same calculations for real-time valuation of solar PV power using PV installations facing southwest and then west.

It is clear that using actual real-time ISO prices, even augmented to raise those that were constrained by low price caps, the difference between solar PV power valuation at a flat rate and real-time rate is fairly small. As we see throughout the table, the difference is largest for a west-facing installation. This is because a west-facing installation produces more of its power in the late afternoon when demand and prices tend to be highest. This at first suggests that one might want to turn the panels west if faced with real-time prices, but an analysis of the total value of the power produced does not support that inference.

Table 2 presents the average hourly production of the PV installations in each of their orientations (the "Avg PV Production" rows) and the total annual value of their production under each of the tariff assumptions. Though west-facing panels produce higher-value power on average, they produce quite a bit less power in total, so much so that the total value of the power they produce is always less than if the installation is oriented southwest and in a few cases less than if they were oriented south. Using the Piso price series

[12] Although almost no customers are currently on RTP in California, the elasticity also represents other departures from complete reliance on supply in the local energy market, including import supply, discretionary use of reserve capacity, and various demand-side management programs.

TABLE 2: Annual Value of Production from 10kW (DC) Solar PV Installation

SACRAMENTO	South Facing PV				Southwest Facing PV				West Facing PV		
	flat-rate	RTP	RTP*		flat-rate	RTP	RTP*		flat-rate	RTP	RTP*
	value	value	value		value	value	value		value	value	value
Piso - North	$810	$839	$882		$779	$831	$875		$688	$743	$781
PisoAugmented	$1,035	$1,024	$1,119		$995	$1,017	$1,107		$879	$906	$978
Psim(-0.025,10%)	$552	$711	$729		$531	$779	$799		$469	$755	$772
Psim(-0.100,99.9%)	$536	$698	$723		$515	$737	$771		$455	$695	$730
Avg PV Prod (kWh/hr - AC)	1.589	1.589	1.589		1.527	1.527	1.527		1.349	1.349	1.349
SAN FRANCISCO	South Facing PV				Southwest Facing PV				West Facing PV		
	flat-rate	RTP	RTP*		flat-rate	RTP	RTP*		flat-rate	RTP	RTP*
	value	value	value		value	value	value		value	value	value
Piso - North	$826	$867	$917		$803	$862	$913		$707	$766	$812
PisoAugmented	$1,056	$1,081	$1,173		$1,026	$1,074	$1,164		$903	$946	$1,022
Psim(-0.025,10%)	$563	$726	$760		$547	$794	$836		$482	$768	$807
Psim(-0.100,99.9%)	$546	$721	$754		$531	$765	$807		$467	$720	$764
Avg PV Prod (kWh/hr - AC)	1.620	1.620	1.620		1.575	1.575	1.575		1.387	1.387	1.387
LOS ANGELES	South Facing PV				Southwest Facing PV				West Facing PV		
	flat-rate	RTP	RTP*		flat-rate	RTP	RTP*		flat-rate	RTP	RTP*
	value	value	value		value	value	value		value	value	value
Piso - South	$767	$826	$868		$747	$827	$878		$661	$745	$797
PisoAugmented	$918	$969	$1,033		$894	$971	$1,049		$792	$869	$947
Psim(-0.025,10%)	$573	$695	$717		$558	$764	$793		$494	$746	$775
Psim(-0.100,99.9%)	$556	$683	$719		$541	$719	$769		$479	$681	$733
Avg PV Prod (kWh/hr - AC)	1.650	1.650	1.650		1.605	1.605	1.605		1.422	1.422	1.422

southwest and south orientation yield nearly identical values, but with the Psim price series southwest orientation is clearly preferred in all locations.[13]

Returning to table 1, compared to use of the actual real-time wholesale prices, the simulated prices produce much larger value differentials from using real-time prices rather than flat rates. Recall that the simulated prices assure that all generation costs are recovered through energy prices, not through capacity payments or other supplementary contracts or services. This causes larger spikes in the simulated prices than in the actual prices, and creates a larger differential between valuing PV power at a flat rate and valuing it at a real-time rate.

Interestingly, the two simulated price series yield fairly similar differentials despite having very different demand elasticities. This is because with both the extremely inelastic demand and the more moderately inelastic demand, the peaker capacity still recovers its capital costs in a relatively small number of high-demand hours. Whether peaker capacity costs are recovered through extremely high prices during four hours of the 5-year sample, as the Psim(-0.025,10%) simulations suggest, or over 750 hours with moderately high prices, as the Psim(-0.100,99.9%) simulations suggest, the solar PVs are producing about the same amount on average during these hours, so still collect the aggregate revenues that the peaker gas plants need to earn to cover their capacity costs.

Controlling for the unobserved correlation between prices and solar PV production also has little effect on the estimates. A very favorable reallocation of production across days, as described earlier, yields only slightly higher valuation of the power than making no adjustment for this unobserved correlation. Thus, for a given price series, the valuations are closely bounded by the estimates with and without the control.

The simulated prices are substantially lower than the actual prices, augmented or not. This is due to the fact that the simulated prices assume a competitive market, which

[13] In fact, the value maximizing orientation is probably never exactly southwest or south, but slightly south or west of southwest. Given the apparent shape of the value as a function of orientation, however, the southwest orientation numbers are probably pretty close to the maximum value.

TABLE 3: Comparison of Annual Production Value to South-Facing Panel Under Flat Rates

SACRAMENTO			South Facing PV					Southwest Facing PV					West Facing PV			
	flat-rate		RTP	pctg	RTP*	pctg		RTP	pctg	RTP*	pctg		RTP	pctg	RTP*	pctg
	value		value	diff	value	diff		value	diff	value	diff		value	diff	value	diff
Piso - North	$810		$839	4%	$882	9%		$831	3%	$875	8%		$743	-8%	$781	-4%
PisoAugmented	$1,035		$1,024	-1%	$1,119	8%		$1,017	-2%	$1,107	7%		$906	-12%	$978	-6%
Psim(-0.025,10%)	$552		$711	29%	$729	32%		$779	41%	$799	45%		$755	37%	$772	40%
Psim(-0.100,99.9%)	$536		$698	30%	$723	35%		$737	38%	$771	44%		$695	30%	$730	36%
Avg PV Prod (kWh/hr - AC)	1.589		1.589		1.589			1.527		1.527			1.349		1.349	
SAN FRANCISCO			South Facing PV					Southwest Facing PV					West Facing PV			
	flat-rate		RTP	pctg	RTP*	pctg		RTP	pctg	RTP*	pctg		RTP	pctg	RTP*	pctg
	value		value	diff	value	diff		value	diff	value	diff		value	diff	value	diff
Piso - North	$826		$867	5%	$917	11%		$862	4%	$913	10%		$766	-7%	$812	-2%
PisoAugmented	$1,056		$1,081	2%	$1,173	11%		$1,074	2%	$1,164	10%		$946	-10%	$1,022	-3%
Psim(-0.025,10%)	$563		$726	29%	$760	35%		$794	41%	$836	48%		$768	36%	$807	43%
Psim(-0.100,99.9%)	$546		$721	32%	$754	38%		$765	40%	$807	48%		$720	32%	$764	40%
Avg PV Prod (kWh/hr - AC)	1.620		1.620		1.620			1.575		1.575			1.387		1.387	
LOS ANGELES			South Facing PV					Southwest Facing PV					West Facing PV			
	flat-rate		RTP	pctg	RTP*	pctg		RTP	pctg	RTP*	pctg		RTP	pctg	RTP*	pctg
	value		value	diff	value	diff		value	diff	value	diff		value	diff	value	diff
Piso - South	$767		$826	8%	$868	13%		$827	8%	$878	14%		$745	-3%	$797	4%
PisoAugmented	$918		$969	5%	$1,033	12%		$971	6%	$1,049	14%		$869	-5%	$947	3%
Psim(-0.025,10%)	$573		$695	21%	$717	25%		$764	33%	$793	38%		$746	30%	$775	35%
Psim(-0.100,99.9%)	$556		$683	23%	$719	29%		$719	29%	$769	38%		$681	22%	$733	32%
Avg PV Prod (kWh/hr - AC)	1.650		1.650		1.650			1.605		1.605			1.422		1.422	

clearly was not the case during the California electricity crisis of 2000-2001.[14] In addition, the simulations assumed a single constant cost of natural gas, $4.25 per million BTU, while the actual cost of gas was well below this level at the beginning of the sample period and above it during most of the time after summer 2000.

Ultimately, the goal of this analysis is to estimate the degree to which a flat-rate retail tariff causes undervaluation of the total power produced by solar PV installations. Table 2 makes clear that if the end-use customer has flexibility in the orientation of the panels, the proper baseline for such a comparison is south orientation under flat rates, because that would yield the largest total production and therefore the largest total value to the customer facing a flat tariff. Thus, table 3, reproduces table 2, dropping the flat rate columns for southwest and west orientation, and adding comparisons of all other values to the baseline of south-facing panels under a flat-rate tariff.

If the end-use customer can orient the panels to maximize their value, table 3 demonstrates that, using either of the Piso price series, southwest and south orientation would yield very similar payoffs under real-time pricing of the power. Accurate accounting for the real-time price of the power would increase the value of the PVs by about 10% in Sacramento or San Francisco, by 12%-14% in LA. If either of the simulated price series obtained, however, the southwest orientation would clearly be more valuable and the difference in value compared to a flat-rate tariff would be much more significant, in the range of 38%-48% in Sacramento and San Francisco and around 29%-38% in LA.

Though I have presented both actual and simulated real-time prices, I am not agnostic as to which are better indicators of the future real-time value of solar PV production. Regardless of whether the electricity industry moves ahead with some sort of "restructuring" or not, the accuracy of these estimates will depend on the degree to which wholesale price spikes are allowed to take place and to significantly contribute to capacity cost recovery by peaker plants. If resource adequacy regulations assure that the system always has excess production capacity and, consistent with this approach, revenues for capacity payments to generators are collected from retail customers in a time-invariant way, then wholesale

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[14] See, for instance, Borenstein, Bushnell and Wolak (2002) and Joskow and Kahn (2002).

prices will accurately indicate that power at peak times is not much more valuable than off-peak. In that case, the calculations using actual prices would be preferred.[15] If a more efficient retail pricing system is used, however, so that price spikes reduce quantity demanded at peak times, then the calculations using simulated prices will more accurately portray the value. Though California has lagged behind other parts of the U.S. – such as Georgia, New York and Florida – in adopting more efficient retail pricing, it seems only a matter of time until a significant change in that direction takes place.

VII. Do Time-of-Use Rates Better Reflect the Value of Solar PV Power?

The previous section compared the wholesale value that customers received for the power produced by their solar panels if they are on a flat-rate tariff with the value they would receive if they faced real-time prices that varied hourly with the wholesale electricity market. Retail real-time pricing does exist in some locations, but it is not widespread.

Time-of-use rates, however, are quite common. With time-of-use rates, the price customers pay for energy varies among preset rates according to a preset schedule. In California, and most other U.S. implementations, during the winter customers face one rate during the day and evening and a different rate in the nighttime. In the summer, there are often three rates: a peak rate in the afternoon, a shoulder rate in the morning and evening, and an off-peak rate at night. On weekends and holidays, the off-peak rate applies throughout the day. Clearly, a customer facing a TOU tariff would be compensated more for its solar panel production in the middle of a summer (weekday) afternoon than he would if he faced a flat-rate tariff. But how far would a simple TOU tariff go towards addressing the problem that I have analyzed?

To answer this question, I constructed TOU rates that were revenue-neutral compared to the flat rate and real-time rates that I have considered in the previous sections. I adopted the time periods used by Pacific Gas & Electric (which serves most of northern California)

[15] This ignores the possibility of solar PVs being considered part of the capacity counted towards resource adequacy. Though that could occur, the degree to which it would enhance the returns to owning PV production would depend idiosyncratically on the structure of the resource adequacy requirement, capacity payments, and special provisions for distributed generation.

in its most common TOU tariff. In the winter, two TOU periods: a peak price in effect 8am-9pm on non-holiday weekdays, and an off-peak price that is effect at all other times. In the summer, there are three TOU periods: Peak is noon-6pm on non-holiday weekdays; Shoulder is 8am-noon and 6pm-11pm on non-holiday weekdays; Off-peak is in effect at all other times. Summer includes June through October and winter is November through May.

The rate for any TOU period is set to equal the weighted-average wholesale price (weighted by system quantity) during all hours in the sample in which that TOU period was in effect. This is the same as the method used to calculate the break-even flat-rate tariff, but now using only selected hours for each TOU period. Thus, this TOU tariff is set to be revenue-neutral compared to both the flat-rate tariff and a real-time pricing tariff that just passes through the wholesale price. As with the calculated flat-rate tariff, the TOU rates vary according to which of the four wholesale price series is used as the basis. Table 4 presents the break-even TOU rates for the 5-year sample period as well as the break-even flat-rate tariff for comparison.

The valuation of Solar PV power at TOU rates is presented in Table 5 along with the real-time wholesale price valuation, which is the same as in Table 1. It is clear from Table 5 that a TOU retail tariff pretty much eliminates the undervaluation of solar PV power that was caused by use of a flat-rate tariff. In many cases, the percentage difference from the RTP value is negative, indicating that solar PV power is actually overvalued with TOU compared to actual wholesale real-time price valuation.

Omitting the correction for unobserved correlation between solar panel power production and system demand, most of TOU valuations are slightly higher than the RTP valuations. Including the correction, most of the TOU valuations are slightly lower than the RTP valuations. In all cases, the difference is no greater than 8%. Thus, it appears that TOU retail rates generate for the customer about the same wholesale value of the power produced by solar panels as the customer would receive if it faced the actual wholesale real-time prices.

TABLE 4: Time-of-Use Rates Assumed for TOU Valuation of Solar PV Power

	Winter Off-peak	Winter Peak	Summer Off-peak	Summer Shoulder	Summer Peak		Flat Rate
Piso - North	$51.91	$61.33	$48.76	$64.06	$89.39		$58.21
PisoAugmented - North	$68.23	$80.17	$54.63	$76.44	$123.68		$74.37
Piso - South	$43.46	$60.21	$40.49	$58.69	$93.26		$53.10
PisoAugmented - South	$51.89	$72.68	$43.08	$66.03	$127.62		$63.56
Psim(-0.025,10%)	$17.35	$34.81	$23.95	$45.68	$183.96		$39.68
Psim(-0.100,99.9%)	$17.37	$35.05	$24.40	$53.04	$157.50		$38.48

TABLE 5: Comparison of Average Wholesale Value of Solar PV using Time-of-Use versus Real-Time Retail Prices

SACRAMENTO	South Facing PV					Southwest Facing PV					West Facing PV				
	TOU	RTP	pctg	RTP*	pctg	TOU	RTP	pctg	RTP*	pctg	TOU	RTP	pctg	RTP*	pctg
	value	value	diff	value	diff	value	value	diff	value	diff	value	value	diff	value	diff
Piso - North	$62.22	$60.30	-3%	$63.38	2%	$63.40	$62.13	-2%	$65.37	3%	$64.12	$62.90	-2%	$66.10	3%
PisoAugmented	$80.15	$73.57	-8%	$80.38	0%	$82.13	$76.05	-7%	$82.77	1%	$83.26	$76.68	-8%	$82.71	-1%
Psim(-0.025,10%)	$53.87	$51.12	-5%	$52.39	-3%	$59.29	$58.25	-2%	$59.72	1%	$63.25	$63.89	1%	$65.31	3%
Psim(-0.100,99.9%	$50.94	$50.13	-2%	$51.97	2%	$55.28	$55.10	0%	$57.59	4%	$58.48	$58.84	1%	$61.76	6%
SAN FRANCISCO	South Facing PV					Southwest Facing PV					West Facing PV				
	TOU	RTP	pctg	RTP*	pctg	TOU	RTP	pctg	RTP*	pctg	TOU	RTP	pctg	RTP*	pctg
	value	value	diff	value	diff	value	value	diff	value	diff	value	value	diff	value	diff
Piso - North	$62.41	$61.12	-2%	$64.62	4%	$63.42	$62.49	-1%	$66.16	4%	$64.14	$63.09	-2%	$66.83	4%
PisoAugmented	$80.56	$76.17	-5%	$82.65	3%	$82.23	$77.89	-5%	$84.37	3%	$83.30	$77.86	-7%	$84.14	1%
Psim(-0.025,10%)	$54.57	$51.16	-6%	$53.51	-2%	$59.55	$57.59	-3%	$60.62	2%	$63.58	$63.20	-1%	$66.42	4%
Psim(-0.100,99.9%	$51.42	$50.80	-1%	$53.12	3%	$55.42	$55.44	0%	$58.52	6%	$58.69	$59.31	1%	$62.89	7%
LOS ANGELES	South Facing PV					Southwest Facing PV					West Facing PV				
	TOU	RTP	pctg	RTP*	pctg	TOU	RTP	pctg	RTP*	pctg	TOU	RTP	pctg	RTP*	pctg
	value	value	diff	value	diff	value	value	diff	value	diff	value	value	diff	value	diff
Piso - South	$58.33	$57.15	-2%	$60.05	3%	$59.52	$58.82	-1%	$62.46	5%	$60.32	$59.83	-1%	$63.97	6%
PisoAugmented	$71.01	$67.03	-6%	$71.48	1%	$72.94	$69.05	-5%	$74.64	2%	$74.24	$69.77	-6%	$76.06	2%
Psim(-0.025,10%)	$50.76	$48.12	-5%	$49.62	-2%	$55.03	$54.34	-1%	$56.39	2%	$58.78	$59.91	2%	$62.23	6%
Psim(-0.100,99.9%	$48.21	$47.30	-2%	$49.77	3%	$51.65	$51.15	-1%	$54.67	6%	$54.72	$54.66	0%	$58.83	8%

VIII. Conclusion

Solar photovoltaic cells remain a relatively expensive way to generate electricity, but with increasing natural gas prices and concerns about greenhouse gasses and terrorist attacks, PVs could begin to look more attractive as the technology improves. To fully understand the costs and benefits of solar PV power requires a careful analysis of all of its market and non-market attributes. In this paper, I have presented a method for analyzing the wholesale value of solar PV power recognizing that it produces a disproportionate amount of its output at times when the weather is sunny and system demand is high.

Applying the method to California, a summer-peaking system, I find that correctly accounting for the time-varying electricity production of solar panels could increase its value substantially compared to a flat-rate tariff. Using actual real-time prices, the change in value is only around 10%, but using prices from a simulation model, which assures that peaking gas capacity covers its fixed costs through high energy prices, the increased value from real-time valuation of solar power could be nearly 50%.

The analysis points out that a flat-rate tariff will cause end-use customers to significantly undervalue the power produced by solar panels. I find, however, that the problem is negligible if the customer is on a time-of-use rate, a simple peak/off-peak tariff in which prices vary systematically by time of day and weekday/weekend. While there are many compelling arguments for instituting dynamic retail pricing, such as real-time pricing, rather than TOU, the valuation of power from solar panels is not one of them.

These results are, of course, only one piece of a larger analysis of the costs and benefits of the solar PVs. The method, however, is straightforward and can easily be applied to areas outside of California so long as data on prices and on PV production are available.

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